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Effect of Oil Shale Recovery Processes on Air Emissions

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16. ABSTRACT

The paper discusses the effect of oil shale recovery processes on air emissions. In developing the analysis for this process comparison, the EPA's Pollution Control Technical Manuals (PCTMs) for various oil shale processes and various PSD Permit Applications were used. The PCTMs present a comprehensive analysis of the heat and material flows in a complete oil shale recovery process. The PSD applications provide controlled air emissions for the specific process considered by the developer. This, the comparison presented in this paper is based on the actual design conditions expected in a full-scale operation. The basic conclusion derived from the analysis is that, although the air emission levels for the different retort processes with controls considered to be Best Available Control Technology (BACT) can vary considerably, sometimes by as much as two orders of magnitude, the application of control techniques that are either improvements over existing technology or more suitable for a specific application, results in similar emission levels for all five processes considered. Although some of the control techniques considered have not been applied specifically to the oil shale recovery process, and therefore cannot be considered as BACT, these techniques have been proven at the full-scale level in various other difficult control applications.

17. KEY WORDS AND DOCUMENT ANALYSIS

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THE EFFECT OF OIL SHALE RECOVERY PROCESSES ON AIR EMISSIONS

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Development of oil shale production processes has led to a variety of retort designs. Figure 1 shows the total facility emissions as reported in the PSD permit applications for seven potential shale oil recovery plants. The actual facility emissions based on the reported processes, in some cases, would be significantly higher if assumptions made by the developers regarding low levels of organic sulfur and nitrogen species in retort gases prove incorrect. The degree of variation in total facility emissions is considerable with complicating tradeoffs. For example, the Clear Creek facility with a Chevron solids recycle retort has very high NO_x and CO emissions. Conversely, the Union facility with a gas recycle retort has much lower CO and NO_x emissions but higher SO_x emissions.

The purpose of this analysis was to evaluate these various processing schemes and determine the effect of improved air pollution controls. The information presented below will show that, with the proper selection of air pollution control techniques, the air emissions for each of these processes can be held to essentially equivalent values.

In developing the analysis for this process comparison, the EPA's Pollution Control Technical Manuals (PCTMs) for various shale oil processes (References 1, 2, 3) and various PSD Permit Applications (References 4, 5, 6, 7, 8, 9, 10) were used. The PCTMs present a comprehensive analysis of the heat and material flows in a complete oil shale recovery process. The PSD applications provide controlled air emissions for the specific process considered by the developer. Thus, the comparison presented in this paper is based on the actual design conditions expected in a full-scale operation.

SHALE OIL RECOVERY PLANT

A shale oil recovery plant is quite complex involving many varied operations. The unit operations required to recover the oil from the shale include:

- mining
  - below-ground
  - above-ground
- retorting
- product recovery
- removal of nitrogen (ammonia and organic nitrogen gases) from the retort gas
- removal of sulfur (hydrogen sulfide and organic sulfur gases) from the retort gas
- gas utilization (retort gas combustion)
- end of pipe controls
- upgrading
- spent shale disposal

Within each of these unit operations there can be a number of process alternatives. The shale can be mined in an open pit mine or a room and pillar mine, or the

oil can be recovered without mining with an in-situ process. The retort heat can be provided by combustion of the spent char within the retort or with a recycled stream which can be either gas or solid. Each of these variations can affect the emission rates. Consequently, consideration of all the potential processing schemes can be quite complicated.

Figure 2 presents some possible processing combinations considered as viable alternatives for full scale processing. The specific process combinations used for this analysis are presented in Table 1.

Table 1. FIVE PROCESSES FOR ANALYSIS

Case No.	Mining	Retort
1	Open pit	direct combustion heat[a] (e.g., Paraho)
2	Room & pillar	direct combustion heat - circular grate (e.g., Superior, Dravo, Allis Chalmers)
3	Room & pillar	indirect combustion[b] gas recycle (e.g., Union)
4	Room & pillar	indirect combustion solids recycle (e.g., Lurgi, Chevron)
5	Modified in-situ	in-situ and indirect heat gas recycle above ground

(a) Direct combustion heat - the heat for retorting is provided by combustion of the spent char within the retort.
(b) Indirect combustion heat - the heat for retorting is provided by combustion of retort gas or spent shale outside of the retort.

In this paper the methodology used to evaluate the various processes will be presented first. Then an evaluation of the sulfur and nitrogen gases produced by the retort for the various processes will be presented along with a discussion of the effect on the acid gas removal processes and net facility emissions. Emissions from other facets of the shale oil recovery operation (e.g., mining, solids handling, spent shale disposal) will then be presented. This is followed by an analysis of the emissions for five typical processes being considered for full scale development.

For each analysis, a base case scenario representative of the process configuration proposed by the developers is presented, and the criteria pollutant emissions are determined. Then two alternative processing schemes to reduce these emissions to their lowest levels are considered.

METHODOLOGY

For this analysis, the oil recovery facility was divided into three basic categories: mining, retort, and upgrade. The emissions associated with mining and solids handling (primarily particulates, carbon monoxide, and nitrogen oxides) are similar to other mining operations. The data provided in the PSD permit applications were used to develop emission rates for each type of unit operations (e.g., blasting, drilling, vehicles, conveying, crushing). The emissions associated with the upgrading process (hydrocarbons from storage and fugitive sources), other than those from the combustion of the retort gas, are similar to other oil refining operations and, again, the PSD permit applications were used to develop estimated emission levels.

The combustion of the retort gas can be the principal source of emissions from the facility and the source most affected by the particular retort process and gas cleanup scheme used.

The primary concern of this analysis is emissions of nitrogen and sulfur oxides and particulates. Emissions of carbon monoxide and hydrocarbons are generally consistent for all processes, with a few exceptions. The combustion of the spent shale can produce very high carbon monoxide emissions, and this will be discussed below for that particular process. High hydrocarbon emission rates can result from certain types of retort processes (e.g., Tosco II) that involve direct contact heating of raw shale or a heat carrier with flue gas. However, this process was not included in this analysis.

To evaluate the many process variations and develop the data necessary to estimate emission levels it was first necessary to determine what process combinations are feasible. The alternatives considered are shown in Figure 1.

The basic design parameters that affect the pollutant emissions for each process were defined. These design parameters are shown in Table 2.

Table 2. DESIGN PARAMETERS USED IN ANALYSIS

Unit Operation	Design Parameter
Mining	Type of Mining open pit room and pillar in-situ
Retort	• Retort Gas Produced, m^3/m^3 of oil • Heating Value of Retort Gas, kJ/m^3 • Partitioning of sulfur and nitrogen
Product recv'ry	None- The product recovery process has no significant effect on emiss.
NH_3 removal	• NH_3 exit concentration, ppm • Organic nitrogen content of retort gas, %
H_2S removal	• H_2S exit concentration, ppm • Organic sulfur content of retort gas, % • Organic sulfur gas removal effic., %
Gas utilization	• Boiler-dilution ratio (dry gas/fuel) • Spent shale combustion exit concentrations for NO_x, SO_x & CO, ppm
End-of-pipe controls	
Particulate	- Baghouse - exit loading, g/m^3
	• Sulfur - FGD - exit SO_x, ppm
	• Nitrogen Ammonia injection - exit NO_x, ppm Staged combus. - exit NO_x & CO, ppm

For each of the unit operations, the design parameters were applied as indicated by either the retort

process conditions, performance of the pollution control equipment, or the reported emissions from the PSD applications. The following discussion presents the rationale for choosing the specific design parameters used in the analysis.

MINING, SOLIDS HANDLING, AND UPGRADING EMISSIONS

The data provided in the PSD permit applications were evaluated to determine typical emission rates for the various unit operations. Figures 3 through 7 show the emission rates from individual sources for the criteria pollutants. For this analysis, all emissions associated with combustion of the retort gas (i.e., upgrade heater, retort heater) are considered as part of the emissions from the retort operation.

The carbon monoxide emission sources (Figure 3) are blasting, below ground vehicles, above ground vehicles, and the combustion of the retort gas in the retort and upgrading process. The hydrocarbon emission sources (Figure 4) are primarily mining vehicles, storage, and fugitive emissions in the upgrading and retort gas combustion. Nitrogen oxide emission sources (Figure 5) are primarily from retort gas combustion and mining vehicles. The only significant sulfur oxide emissions source (Figure 6) is the combustion of the retort gas, with mining and upgrading adding a relatively small amount.

The particulate emission sources (Figure 7) are those associated with below ground mining (drilling, blasting, conveying, crushing, engines), above ground mining (surface soils removal, second and third degree crushing, conveying, storage, and spent shale disposal), retort gas combustion (steam generator, retort heater, and upgrade heaters), above ground vehicles, and fugitive emissions from truck traffic.

The values from the PSD permit applications presented for mining and upgrading emissions were used in the overall facility emission estimates presented below. The emissions from retort gas combustion were calculated as described below.

The choice of mining technique determines the emission rates. The values used were developed from the PSD analysis for room and pillar mining and from the literature for open pit mining (Reference 1). The emission rates used are shown in Table 3.

Table 3. EMISSION RATES FOR MINING (Above- and Below-Ground)

Type of Mining	Emissions, kg/1000 m^3 of Oil				
	CO	HC	NO_x	SO_x	PM
Open pit	370	50	470	40	410
Room & pillar	150	20	350	20	180
Room & pillar with catalytic converters on engines	15	2	350	20	180

RETORT GAS

The emissions from the combustion of the retort gas are determined by:

- volume and heating value of the retort gas
- presence of sulfur in the gas
- presence of nitrogen as ammonia or organic nitrogen compounds

The retort gas flow rates for three types of retorts are shown in Table 4.

Table 4. RETORT GAS PRODUCTION RATES

Type Retort	Gas Produced m^3/m^3 of Oil	Heating Value g-cal/L
In-situ	7000	9000
Direct combustion	1800	9000
Indirect combustion	180	90,000

The in-situ process produces the highest retort gas flow rate due to the combined effect of the higher retort temperatures converting more of the kerogen to gas and the higher dilution gas flow required to provide adequate oxygen to burn the shale. The direct combustion retort has similar conditions (i.e., high temperatures and requirement for adequate oxygen for combustion) but to a lesser degree than the in-situ retort and, consequently, has lower retort gas flow rates. The indirect combustion process has the lowest retort gas flow rate due to the lower retort temperatures and low gas flow rate with no dilution required to provide oxygen.

The heating value of the retort gas is determined by the amount of dilution gas. In-situ and direct combustion retorts produce low heating value gas at 9000 g-cal/L (100 Btu/scf) and the indirect combustion retort produces high heating value gas at 90000 g-cal/L (1000 Btu/scf).

The retort gas flow and heating value determine the net exhaust gas flow after combustion. As the performance of the air pollution controls is often determined by an exit concentration (ppm or g/m^3), high gas flow rates result in higher pollutant emissions.

Sulfur Gases

During the retorting, the sulfur in the raw shale is partitioned to the spent shale (60 percent), oil (10 percent), and retort gas (30 percent). The significant variations in raw shale sulfur content, percentage of sulfur partitioned to the gas phase, and chemical structure of these sulfur gases result in the sulfur gas cleanup strategy being quite difficult.

The sulfur emission problem can be solved either by removing the sulfur prior to combustion or by adding a flue gas desulfurization process after combustion. As the combustion process dilutes the pollutant concentra-

tions and increases the gas flow rate, the economically preferred technique usually is sulfur removal prior to combustion.

The form of the sulfur in the gas is extremely important when considering sulfur removal processes. Sulfur recovery processes that have been considered for cleaning the retort gas prior to combustion are not effective in removing organic sulfur compounds which can amount to as much as 10-16 percent of the total sulfur in the retort gas. Consequently, the effectiveness of these cleanup processes depends on the relative amounts of organic sulfur to H_2S. Even high efficiencies of H_2S removal (99 percent) are not sufficient to reduce the sulfur emissions below the 850 kg/1000 m^3 of oil (0.3 lb/bbl) regulatory level for Colorado if there are significant amounts of organic sulfur gases.

To avoid the costly alternative of adding an end-of-pipe flue gas desulfurization, two alternatives can be considered. The first, the activated carbon-hypochlorite H_2S removal process, is an improvement on the H_2S scrubbing process which also removes organic sulfur species (Reference 11). Therefore, this process is effective for removing sulfur gases prior to combustion, eliminating the need for more expensive post combustion control. The activated carbon-hypochlorite process reports removal of 99+ percent of the H_2S and 90-98+ percent of the organic sulfur gases. This results in a net sulfur removal efficiency of 99 percent and sulfur emissions (SO_x) of 500 kg/1000 m^3 oil (0.17 lb/bbl) even when the organic sulfur gases are 15 percent of the total sulfur.

The second alternative to the use of post-combustion SO_x control is the indirect combustion-solids recycle retort process which limits sulfur gas emissions by the chemistry of the retort and combustion process. The sulfur contained in the retort gases from the recycle solids process can be as low as 1 percent of the total sulfur content in the feed with proper design of the retort. [The remaining sulfur is partitioned to the oil (10 percent) and the spent shale (89 percent)]. Therefore, the amount of organic sulfur is minimal, and the H_2S removal processes alone are sufficient to reduce the sulfur emissions below the regulatory limit.

The design conditions used for the H_2S removal process determine the residual H_2S and organic sulfur in the retort gas that eventually are emitted as sulfur oxides. The processes considered are:

1. Direct or indirect conversion of the sulfur (e.g., Stretford, Lo-Cat, Unisulf, alkaline, or amine scrubbing)

   H_2S exit concentration = 50 ppm
   organic sulfur assumed at 5 percent of total sulfur in retort gas - no removal

2. activated carbon-hypochlorite process

   H_2S exit concentration = 10 ppm
   organic sulfur - 90 percent removal

Two process operations result in the direct emission of sulfur oxides from the retort: the circular grate, direct heated retort and the fluidized bed combustion of the spent shale. The design conditions for these two processes were taken from the literature (References 8 and 9).

Circular Grate Retort - SO_x = 175 ppm in retort gas

Fluidized Bed Spent Shale Combustor in Retort Gas - SO_x = 20 ppm

Nitrogen Gases

The removal of nitrogen gases is also difficult to predict due to the degree of variability of nitrogen content in shale, partitioning between gas, oil, and spent shale, and chemical form of the gaseous nitrogen species.

Using the data reported in the PSD permit applications and the Pollution Control Technical Manuals, the partitioning of the nitrogen was estimated as shown in Table 5.

Table 5. PARTITIONING OF NITROGEN IN RETORT

Process		% of Raw Shale Nitrogen in Product		
		Spent Shale	Oil	Retort Gas
In-situ (MIS)		21	25	54
Solids Recycle	(Lurgi) (Chevron)	5	55	10[a]
Direct Combus'n	(Paraho)	33	37	30

(a) Remaining nitrogen content in the spent shale after retorting is burned in the lift pipe or fluidized combustor and exits with the flue gas.

The nitrogen content of the retort off-gas consists primarily of ammonia with smaller amounts of other nitrogen compounds. In a semi-quantitative investigation of nitrogen-containing species from an in-situ and above-ground retort process, hydrogen cyanide, various nitriles, pyrrole, pyridine, methyl and diethyl aniline, and other nitrogen gas species were identified (Reference 12). The organic nitrogen content of the retort gas was found to be as much as 1-2 percent of the ammonia content.

The presence of organic nitrogen species presents the same problem for limiting fuel-related NO_x emissions as that described above for the SO_x emissions; namely that the removal processes generally considered are not effective in reducing the organic nitrogen content of the retort gas.

The primary nitrogen removal technique considered is removal of ammonia from the retort gas by a water-wash absorption tower followed by an ammonia recovery stripper. The outlet ammonia concentration is deter-

mined by the effectiveness of the ammonia absorber. At atmospheric pressure the equilibrium exit partial pressure for ammonia at 50°C is 0.5 mm Hg.

The nitrogen content of the treated retort gas, and the subsequent NO_x emissions from combustion of the retort gas, is determined by:

- the exit gas ammonia concentration (660 ppm NH_3)
- the amount of retort gas produced by the retort (Table 4)
- the amount of nitrogen partitioned to the retort gas (Table 5)
- the percentage of nitrogen present as organic nitrogen compounds (2 percent)

The design conditions used to determine the NO_x emissions from burning the retort gas are:

- water wash – NH_3 in exit gas based on NH_3 partial pressure = 0.5 mmHg
  organic nitrogen based on 2% of nitrogen in retort gas and no removal with water wash
  – thermal NO_x from retort gas rate, heating value and 0.2 lb/10^6 Btu
- acid wash – same as water wash except NH_3 assumed = 10 ppm

The processes that utilize the combustion of high-nitrogen-content spent shale for energy recovery can produce high NO_x emissions if proper staging of the combustion is not used. For PSD permit applications, NO_x emissions were based on a high estimate of 15 percent for the conversion of the nitrogen in the spent shale to NO_x in the combustor. This level of conversion was also found by Lawrence Livermore Laboratory investigators who did not attempt to stage the combustion (Reference 12).

The principle of NO reduction in a staged combustor can be applied to reduce these high NO_x emissions to approximately 3 percent nitrogen conversion to NO_x.

RETORT GAS COMBUSTION AND END-OF-PIPE

The end-of-pipe controls are those either added after combustion of the retort gas to remove particulate, NO_x, and SO_x, or incorporated as part of the combustion process as in staged combustion for NO_x control.

Particulate

For particulate control, two alternatives were considered. The first is the base case using a standard baghouse. The second control technique is the combined dry venturi-baghouse (Reference 13).

The dry venturi-baghouse combination provides for particulate control that is somewhat independent of type of particulate. The applicants for PSD permits all considered a minimum particulate exit loading of 0.07 g/m^3 (0.03 gr/scf) which was based on standard technology within the limits of the unknowns associated with oil shale particulate. By capturing the small particles on larger target particles of specified physical properties, the dry venturi eliminates the major uncertainties in designing baghouses with respect to particulate type and size.

Two design conditions based on the face velocity in the baghouse of 0.5 and 1.5 m/sec were used (Reference 14):

particulate loading g/m^3	face velocity m/sec
0.02	0.5
0.001	1.5

Sulfur Oxides

If the H_2S (and organic sulfur) removal is not sufficient to reduce the sulfur emissions to an acceptable level, a post-combustion flue gas desulfurization system must be added. This could be either a wet or dry scrubber.

Another sulfur control technique is the use of a spent shale combustor. The combustion of the spent shale has two important advantages: 1) recovery of the energy value of the char, and 2) reduction of the sulfur oxide emissions due to the scrubbing nature of the spent shale. However, spent shale combustion also has two distinct disadvantages: 1) high emissions of NO_x from the nitrogen in the spent shale, and 2) high emissions of CO due to incomplete combustion. These emissions (NO_x and CO) are discussed in the following section.

The design conditions for SO_x emissions used in the analysis are:

- Flue Gas Desulfurization – 50 ppm SO_x exit concentration
- Combustion of spent shale with retort gas
  – 10 ppm SO_x
  – 300 ppm NO_x
  – 1000 ppm CO

Nitrogen Oxides

Two controls were considered for reducing post-combustion NO_x emissions. The first is ammonia injection; this technique has been applied successfully in utility boilers and could be used when the retort gas is burned in a conventional boiler for steam and electrical generation.

The second NO_x control considered is staged combustion which has particular advantages for spent shale combustion due to its ability to adequately control fuel related NO_x. The staged combustion could be applied to either the conventional boiler or the spent shale combustor.

Selective catalytic reduction (SCR) was not considered due to its potential for poisoning the catalyst.

The retort gas particulate contains a wide variety of heavy metals which have a deleterious effect on catalyst life. In addition, there are still a number of unknown factors which can affect the long term catalyst performance that have not been completely identified. For example, it had been assumed that the mercury associated with the retort gas was in the form of elemental mercury and would be substantially removed prior to combustion during the standard gas cleaning (ammonia and hydrogen sulfide removal) processes. However, it has been shown that the mercury is present primarily as methyl mercury which is volatile and is present in the retort gas during combustion (Reference 15). Consequently, any post-combustion control processes must be capable of handling these emissions of elemental and oxides of mercury. This is only one instance where unknown factors could have a negative effect on catalyst performance. Consequently, due to the inherently variable nature of the retort gas from an oil shale retort and the known presence of many catalyst poisons, the use of SCR was not considered.

There is a tradeoff between the NO_x and CO emissions in the spent shale combustor. As indicated above, the NO_x and CO emissions are quite high (300 and 1000 ppm, respectively). Higher combustor temperatures increase the NO_x emissions but decrease the CO emissions. In the range of 600-800°C the NO_x emissions can range from 250 to over 600 ppm, while the CO emissions can vary from 200 to over 1000 ppm at the lower temperatures with low excess oxygen.

In addition, the staged combustion technique of controlling fuel related NO_x depends on low excess oxygen (perhaps sub-stoichiometric combustion) which would further increase the CO emissions.

The fluidized bed combustor has limitations in process control which result in its inability to provide conditions that result in adequate staging for NO_x control. However, a cascading bed combustor may be designed as a staged device (Reference 12). Consequently, combustion conditions can be controlled at each stage of the process, alternating between fuel rich and fuel lean zones to reduce the NO formed to N_2 and complete the combustion of the CO formed to CO_2.

There are as yet no specific test results of the staged combustion with spent shale. However, the reaction kinetics of the reduction of NO to N_2 with spent shale have been investigated (Reference 12), and the engineering design of the cascading bed combustor is ideal for a staged system with easy means for controlling the process conditions.

The design conditions for post-combustion NO_x control are:

- NH_3 injection - 20 ppm NO_x exit concentration
- Cascading bed combustor - 50 ppm NO_x
  - 50 ppm CO

EMISSIONS FROM RETORT GAS COMBUSTION

The results for the emissions from the retort gas combustion from the analysis for all five cases are shown for particulates, sulfur oxides, and nitrogen oxides in Tables 6, 7, and 8, respectively. The total facility emissions for each of the five cases are shown in Tables 9 through 13. The emissions from combustion of the retort gas for particulates, nitrogen oxides, and sulfur oxides, are also shown in Figures 8, 9, and 10, respectively.

These figures indicate that there is wide variation in emission levels for the five processes based on the present day technology (Base Case conditions). For particulates, the emission levels vary from 200 to 800 kg/1000 m^3 of oil; for nitrogen oxides the emission levels vary from 1000 to 8000 kg/1000 m^3 of oil; for sulfur oxides the emission levels vary from 350 to 3000 kg/1000 m^3 of oil.

The first alternative considered was the use of the activated carbon enhanced H_2S removal process, an acid wash for improved ammonia removal, and the addition of a dry venturi-baghouse for post-combustion particulate control. Referring to Figures 8, 9, and 10, the emission levels for alternate No. 1 show considerably less variation, particularly for sulfur oxides (range from 100 to 250 kg/1000 m^3 of oil) and particulates (range from 50 to 200 kg/1000 m^3 of oil). The variation of nitrogen oxide emissions is still considerable, ranging from 1000 to 4000 kg/1000 m^3 of oil. Essentially, the acid wash removes only the residual ammonia (without affecting the organic nitrogen content) and has no effect on the thermal NO_x; therefore, there is relatively little improvement in the NO_x emission rate.

The second alternative considered was the use of ammonia injection for NO_x control from boiler and/or furnace combustion, the use of staged combustion for control of NO_x emissions from the spent shale combustor, and the dry venturi-baghouse with an increased space velocity which improves collection performance at the expense of increased pressure drop. Again, referring to Figures 8, 9, and 10, it is apparent that the addition of these controls essentially levels the performance of all five processes.

Figures 11, 12, and 13 show the particulate, nitrogen oxide, and sulfur oxide emission levels for alternate No. 2 conditions along with the total facility emissions. The particulate emissions, Figure 11, still show variation from 4 to 12 kg/1000 m^3 of oil. However, the absolute value is considerably less than particulate emissions from the mining and solids handling operations, and the total facility is essentially equivalent for all five cases, ranging from 180 to 200 kg/1000 m^3 of oil.

The nitrogen oxide emissions (Figure 12) range from 75 to 500 kg/1000 m^3 of oil. While this is still a sig-

nificant variation, again the absolute magnitude of the values is such that the net variation in the total NO_x emissions for the five facilities is less than a factor of 2, ranging from 400 to 800 kg/1000 m^3 of oil.

The sulfur oxide emissions (Figure 13) range from 100 to 250 kg/1000 m^3 of oil and are essentially the same for the total facility as there are no other significant sources of sulfur emissions.

The basic conclusion derived from the above analysis is that, although the air emission levels for the different retort processes with controls considered to be Best Available Control Technology (BACT) can vary considerably, sometimes by as much as two orders of magnitude, the application of control techniques that are either improvements over existing technology or more suitable for a specific application, results in similar emission levels for all five processes considered. This statement does need to be qualified by the fact that some of the control techniques considered have not been applied specifically to the oil shale recovery process, and therefore cannot be considered as BACT. However, these techniques have been proven at the full scale level in various other difficult control applications.

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Table 6. PARTICULATE EMISSIONS

Case Process	HHV cal/g	Retort Gas ft^3/ bbl	m^3/m^3 Oil	Combust'n Dilution Ratio	Gas Flow m^3/m^3 Oil	Base: Part. Loading g/m^3	Base: kg/ 1000 m^3 of Oil	Alt. 1 Face Velocity = 1.5 ft/sec: Part. Loading g/m^3	Alt. 1: kg/ 1000 m^3 of Oil	Alt. 2 Face Velocity = 3.5 ft/sec: Part. Loading g/m^3	Alt. 2: kg/ 1000 m^3 of Oil
1. Direct combustion	9000	10000	1761	2	3521	0.07	246	0.02	70	0.001	4
2. Direct combustion circular	9000	10000	1761	2	3521	0.07	246	0.02	70	0.001	4
3. Indirect combust-gas	90000	1000	176	15	2641	0.07	185	0.02	53	0.001	3
4. Indirect combust-solids-recy.	9000	1000	176	15	2641	0.07	185	0.02	53	0.001	3
fluidized bed comb.		53000	9331	1	9331	0.07	653	0.02	187	0.001	9
TOTAL		54000	9507		11972	0.07	838	0.02	24	0.001	12
5. Modified in-situ[a]	9000	30000	5282	2	10563	0.07	739	0.02	211	0.001	11
above ground-ind. gas recy.	90000	400	70	15	1056	0.07	74	0.02	21	0.001	1
TOTAL		30400	5352		11619		813		232		12

(a) based on 60% of oil produced

Table 7. SULFUR OXIDE EMISSIONS

Case Process	H_2S ppm	Organic S 5% of H_2S kg/1000 m^3 Oil	SO_x Emission kg/1000 m^3 Oil H_2S	SO_x Emission kg/1000 m^3 Oil Total	SO_x Exit ppm	H_2S (SO_x) ppm	Removal Eff. for Organics %	SO_x Emission kg/1000 m^3 Oil H_2S	SO_x Emission kg/1000 m^3 Oil Total	SO_x Exit ppm
	Activated Carbon Process									
1. Direct combustion	50	1197	199	2593	736	10	90	40	159	45
2. Direct combustion-circular grate	175[a]	0		370	105	50[a]			106	50
3. Indirect combustion-gas recycle	50	1197	20	2414	914	10	90	4	124	47
4. Indirect combustion-solid recycle	50	43[b]	20	106	40	10	90	4	8	3
fluidized	20			224	24				224	24
			0	330						
5. Modified in-situ	50	718	597	2033	192	10	90	119	191	18
above ground-indirect gas recy.	50	480	8	968	916	10	90	2	50	47
				3000					241	

(a) 175 ppm SO_x

(b) low organic sulfur due to solids capture of H_2S in retort

Table 8. NITROGEN OXIDE EMISSIONS

Case Process	NH_3 Part. Press. = 0.5mmHg Exit kg/1000 m^3 Oil	Organic Nitrogen 2% of N	Fuel NO_x kg/1000 m^3 of Oil	Thermal NO_x	Total NO_x	Exit Conc NO_x ppm	Alt.1 Acid wash NH_3, ppm = 10 Organic N =2% Fuel NO_x	NO_x Total	Exit Conc NO_x ppm		Alt. 2 NH_3 Injection Exit Conc NO_x ppm	NO_x Total kg/1000 m^3 Oil
1. Direct combustion	790	256	2242	570	2812	799	586	1156	328	NH_3-inj	20	85
2. Direct combustion-circular	790	256	2242	570	2812	799	586	1156	328	NH_3-inj	20	85
3. Indirect combust-gas recycle	79	85	351	570	921	349	186	756	286	NH_3-inj	20	63
4. Indirect combust-solid recycle	79	85	351	570	921	349	186	756	286	NH_3-inj	20	63
fluidized	300[a]		3359	0	3359	360		3359	360	Stgd/cbn	50	560
			0	0	4281			4115				623
lift gas					3457			3291				486
5. Modified in-situ-	2370	258	5632	1710	7342	695	665	2375	225	NH_3-inj	20	254
above ground-in	32	34	141	228	369	349	74	302	286	NH_3-inj	20	25
												279

(a) Based on 15% conversion of nitrogen in spent shale to NO_x.

Table 9. TOTAL FACILITY EMISSIONS

Case 1 - Direct Combustion
(Paraho type retort)

Base Conditions; H_2S removal (50 ppm), NH_3 water wash
Particulate loading = 0.07 g/m^3

Emissions, kg/1000 m^3 of oil

Base Case Source	CO	HC	NO_x	SO_x	PM
Open pit	370	50	471	38	410
Retort gas	125	35	2812	2593	246
Upgrade	25	150			
Total	520	235	3283	2631	656

Alternate 1 SO_x - H_2S removal - activated carbon
NO_x - NH_3 removal - water & acid wash
PM - dry venturi & baghouse
room & pillar mining

Pollutant	CO	HC	NO_x	SO_x	PM
Room & pillar	150	20	345	20	181
Retort gas	125	35	1156	159	70
Upgrade	25	150			
Total	300	205	1501	179	251
Reduction	220	30	1782	2451	405
% Reduction	42	13	54	93	62

Alternate 2 NO_x - ammonia injection
PM - dry venturi/baghouse
HC & CO - vehicles
catalytic converter

Pollutant	CO	HC	NO_x	SO_x	PM
Room & pillar	15	2	345	20	181
Retort gas	125	35	85	159	4
Upgrade	2	60			
Total	142	97	430	179	185
Reduction	158	108	1071	0	67
% Reduction	52	53	71	0	27

Table 10. TOTAL FACILITY EMISSIONS

Case 2 - Direct Combustion
Circular Grate Retort

Base Case	Emissions, kg/1000 m^3 of oil				
Pollutant	CO	HC	NO_x	SO_x	PM
Room & pillar	150	20	345	20	181
Retort gas	125	35	2812	370	246
Upgrade	25	150			
Total	300	205	3157	390	427

Alternate 1 SO_x - Flue Gas Desulfurization
NO_x - NH_3 removal - water & acid wash
PM - dry venturi/baghouse
HC & CO - vehicles
catalytic converter

Pollutant	CO	HC	NO_x	SO_x	PM
Room & pillar	15	2	345	20	181
Retort gas	125	35	1156	106	70
Upgrade	2	60			
Total	142	97	1501	126	251
Reduction	158	108	1656	264	176
% Reduction	52	53	52	68	41

Alternate 2 NO_x - ammonia injection
PM - dry venturi/baghouse

	CO	HC	NO_x	SO_x	PM
Room & pillar	15	2	345	20	181
Retort gas	125	35	85	106	4
Upgrade	2	60			
Total	142	97	430	126	185
Reduction	0	0	1226	0	66
% Reduction	0	0	74	0	26

Table 11. TOTAL FACILITY EMISSIONS

Case 3 - Indirect Combustion
Gas Recycle Retort (Union)

Base Case Process	Emissions, kg/1000 m^3 of oil				
	CO	HC	NO_x	SO_x	PM
Room & pillar	15	20	345	38	181
Retort	125	35	921	2414	185
Upgrade	25	150	-------No	Data---------	
Total	165	205	1266	2452	366

Alternate 1 NO_x - NH_3 removal - water & acid wash
SO_x - H_2S removal - activated carbon
PM - dry venturi/baghouse

Pollutant	CO	HC	NO_x	SO_x	PM
Room & pillar	15	2	345	20	181
Retort	125	35	756	124	53
Upgrade	2	60			
Total	142	97	1101	144	234
Reduction	22	108	166	2308	132
% Reduction	14	53	13	94	36

Alternate 2 NO_x - ammonia injection
PM - dry venturi/baghouse

Pollutant	CO	HC	NO_x	SO_x	PM
Room & pillar	15	2	345	20	181
Retort gas	125	35	63	124	3
Upgrade	2	60			
Total	142	97	408	144	184
Reduction	0	0	692	0	50
% Reduction	0	0	63	0	21

Table 12. TOTAL FACILITY EMISSIONS

Case 4 - Indirect Combustion
Solids Recycle/Fluidized Bed Combustor

	Emissions, kg/1000 m^3 of oil				
Process	CO	HC	NO_x	SO_x	PM
Room & pillar	150	20	345	20	181
Retort gas	125	35	921	106	185
Combustion	11197		3359	224	653
Upgrade	25	150	-------No Data----------		
Total	11497	205	4626	350	1019

Alternate 1
NO_x - NH_3 removal - water & acid wash
SO_x - H_2S removal-activated carbon
PM - dry venturi/baghouse
HC & CO - vehicles
catalytic converter

	CO	HC	NO_x	SO_x	PM
Room & pillar	15	2	345	20	181
Retort gas	125	35	756	8	53
Combustion	11197		3359	224	187
Upgrade	2	60			
Total	11340	97	4460	252	420
Reduction	158	108	166	98	599
% Reduction	1	53	4	28	59

Alternate 2
NO_x - ammonia injection for retort
staged combustion for combustor gas
cascading bed spent shale combustor
PM - dry venturi

	CO	HC	NO_x	SO_x	PM
Room & pillar	15	2	345	20	181
Retort gas	125	35	63	8	3
Combustion	423		423	169	9
Upgrade	2	60			
Total	565	97	831	197	193
Reduction	10775	0	3629	55	227
% Reduction	95	0	81	22	54

Table 13. TOTAL FACILITY EMISSION

Case 5 - Modified In-situ
Indirect Combustion Above-Ground

	Emissions, kg/1000 m^3 of Oil				
	CO	HC	NO_x	SO_x	PM
Room & pillar	150	20	345	20	181
Retort gas in-situ	72	35	7342	2033	739
Above ground	53		369	968	74
Upgrade	25	150			
Total	300	205	8056	3020	994

Alternate 1 NO_x - NH_3 removal - water & acid wash
SO_x - H_2S removal-activated carbon
PM - dry venturi/baghouse
HC & CO - vehicles
catalytic converter

	CO	HC	NO_x	SO_x	PM
Room & pillar	15	2	345	20	181
Retort gas in-situ	72	35	2375	191	211
Above ground	53	0	302	50	21
Upgrade	2	60			
Total	142	97	3022	261	413
Reduction	158	108	5034	2760	581
% Reduction	52	53	62	91	58

Alternate 2 NO_x - ammonia injection
PM - dry venturi/baghouse

	CO	HC	NO_x	SO_x	PM
Room & pillar	15	2	345	20	181
Retort gas in-situ	72	35	254	191	11
Above ground	53	0	25	50	1
Upgrade	2	60			
Total	142	97	624	261	193
Reduction	0	0	2398	0	221
% Reduction	0	0	79	0	53

Figure 1.

TOTAL FACILITY EMISSIONS SUMMARY

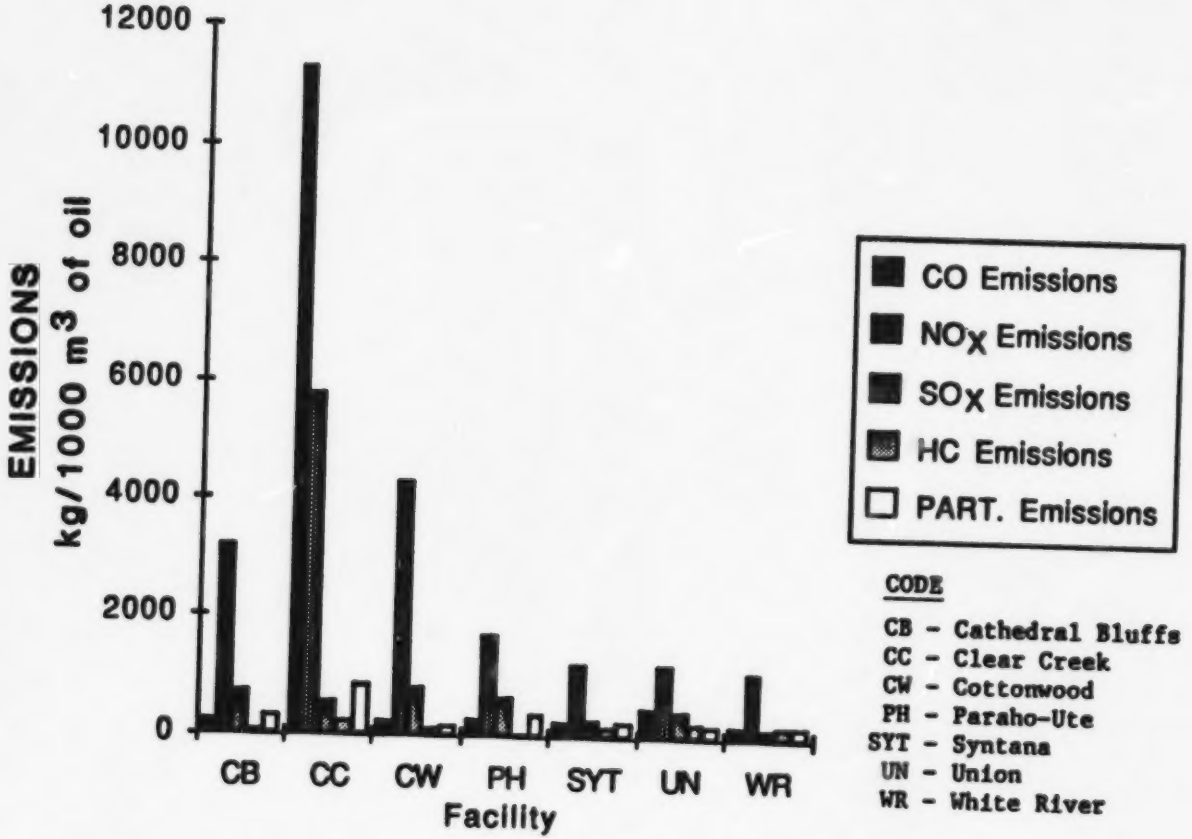

Figure 2.

POSSIBLE PROCESSING COMBINATIONS

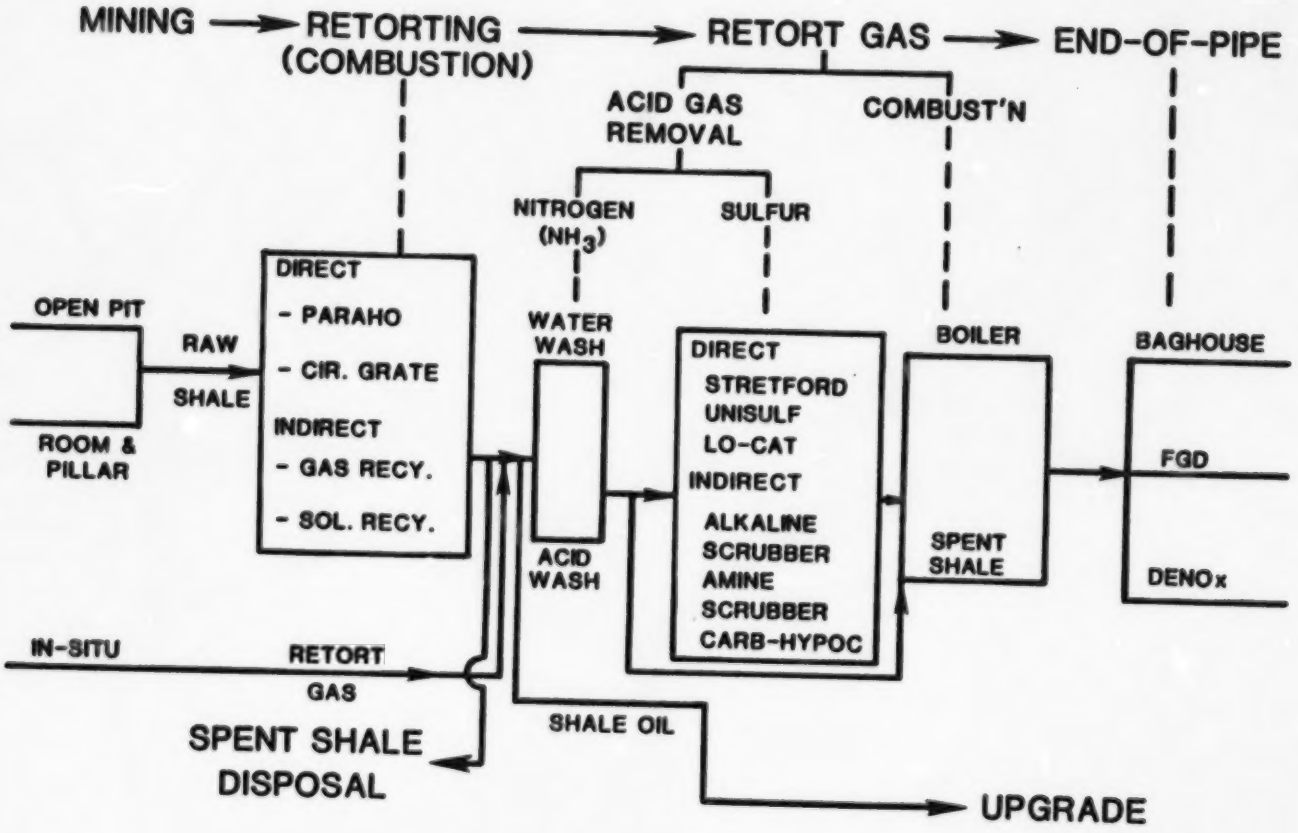

Figure 3.

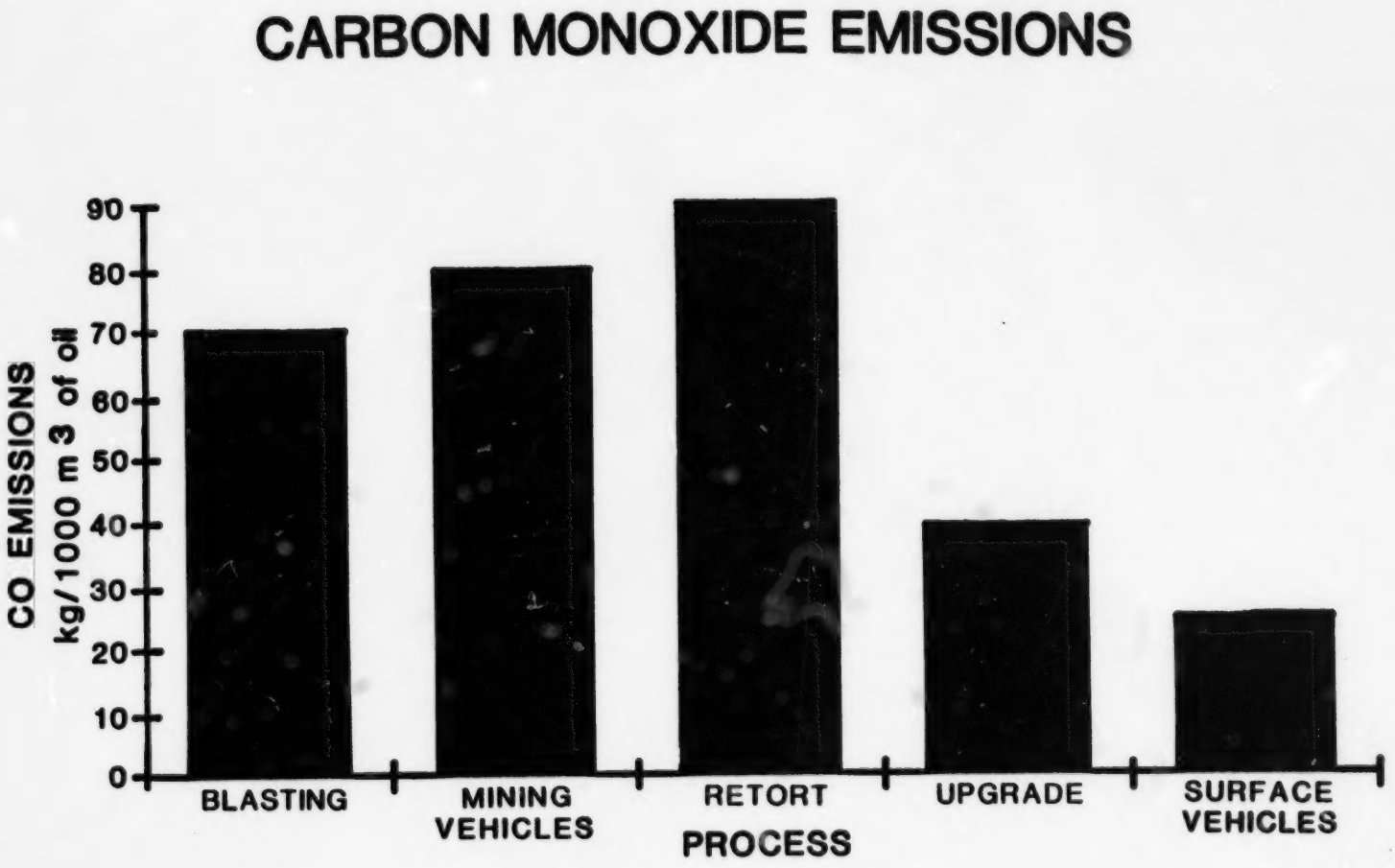
CARBON MONOXIDE EMISSIONS
CO EMISSIONS
kg/1000 m 3 of oil
90
80
70
60
50
40
30
20
10
0
BLASTING
MINING VEHICLES
RETORT
UPGRADE
SURFACE VEHICLES
PROCESS

Figure 4.

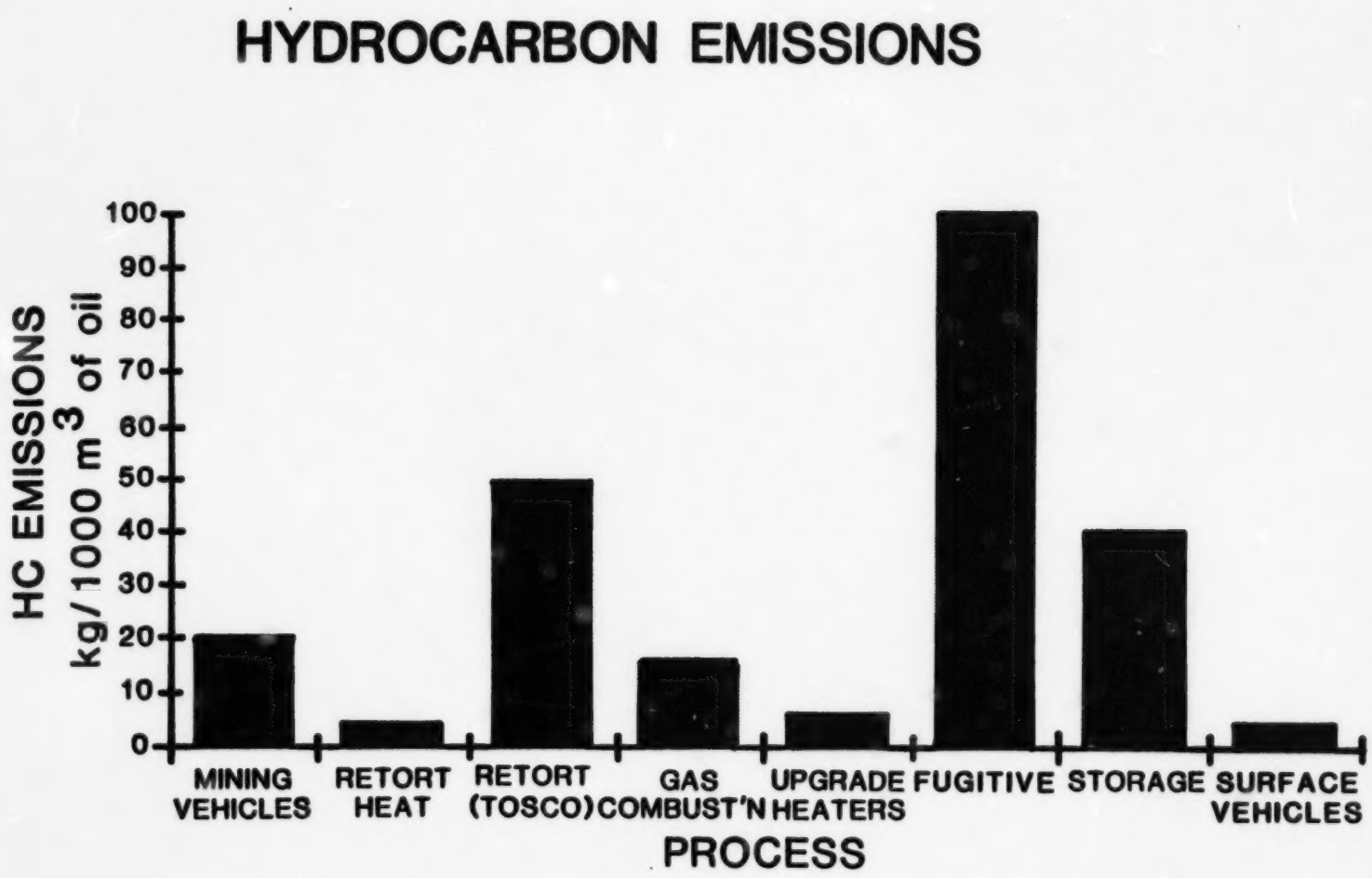
HYDROCARBON EMISSIONS
HC EMISSIONS
kg/1000 m3 of oil
100
90
80
70
60
50
40
30
20
10
0
MINING VEHICLES
RETORT HEAT
RETORT (TOSCO)
GAS COMBUST'N
UPGRADE HEATERS
FUGITIVE
STORAGE
SURFACE VEHICLES
PROCESS

Figure 5.

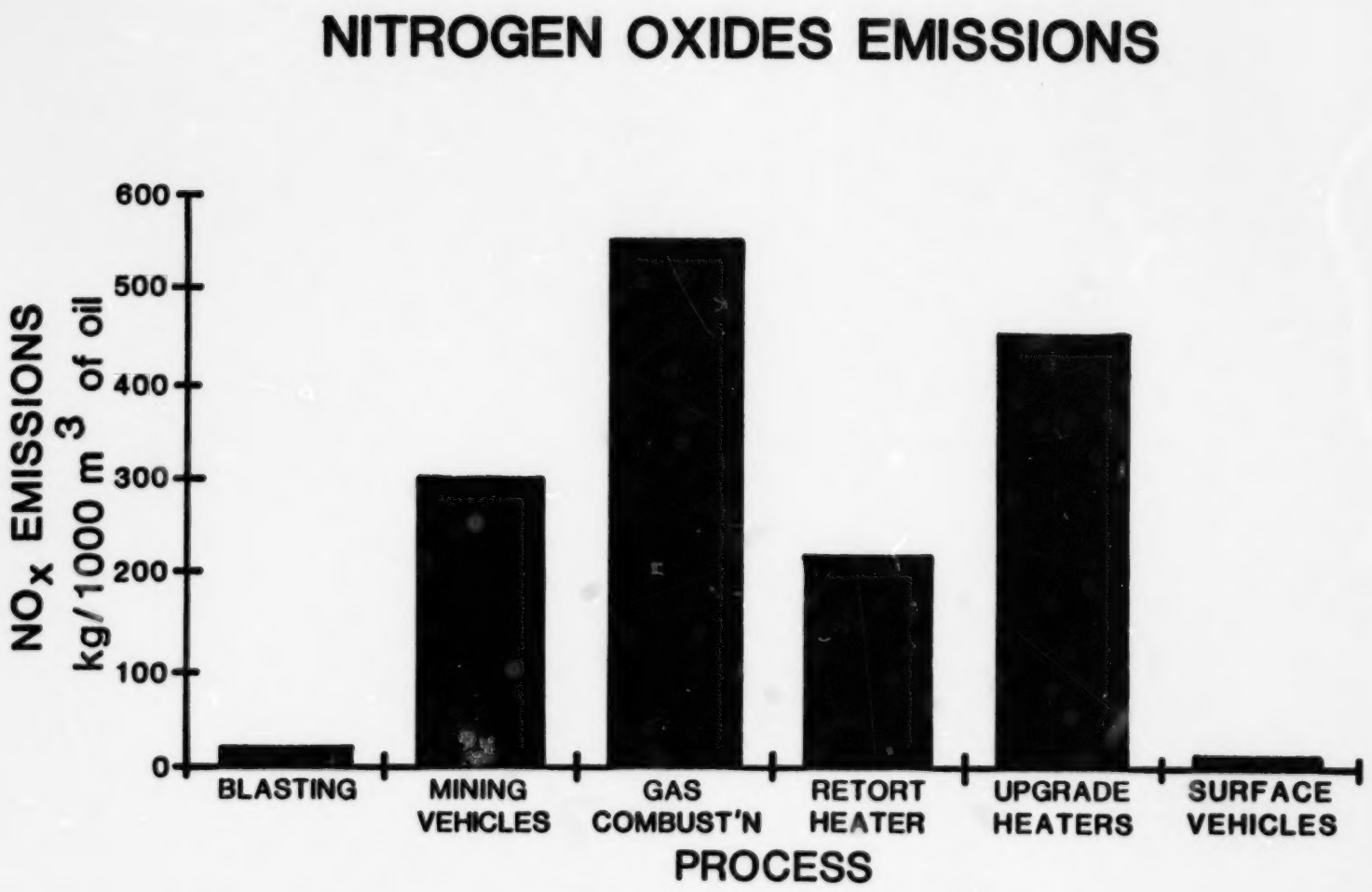
NITROGEN OXIDES EMISSIONS
NO_x EMISSIONS
kg/1000 m^3 of oil
600
500
400
300
200
100
0
BLASTING
MINING VEHICLES
GAS COMBUST'N
RETORT HEATER
UPGRADE HEATERS
SURFACE VEHICLES
PROCESS

Figure 6.

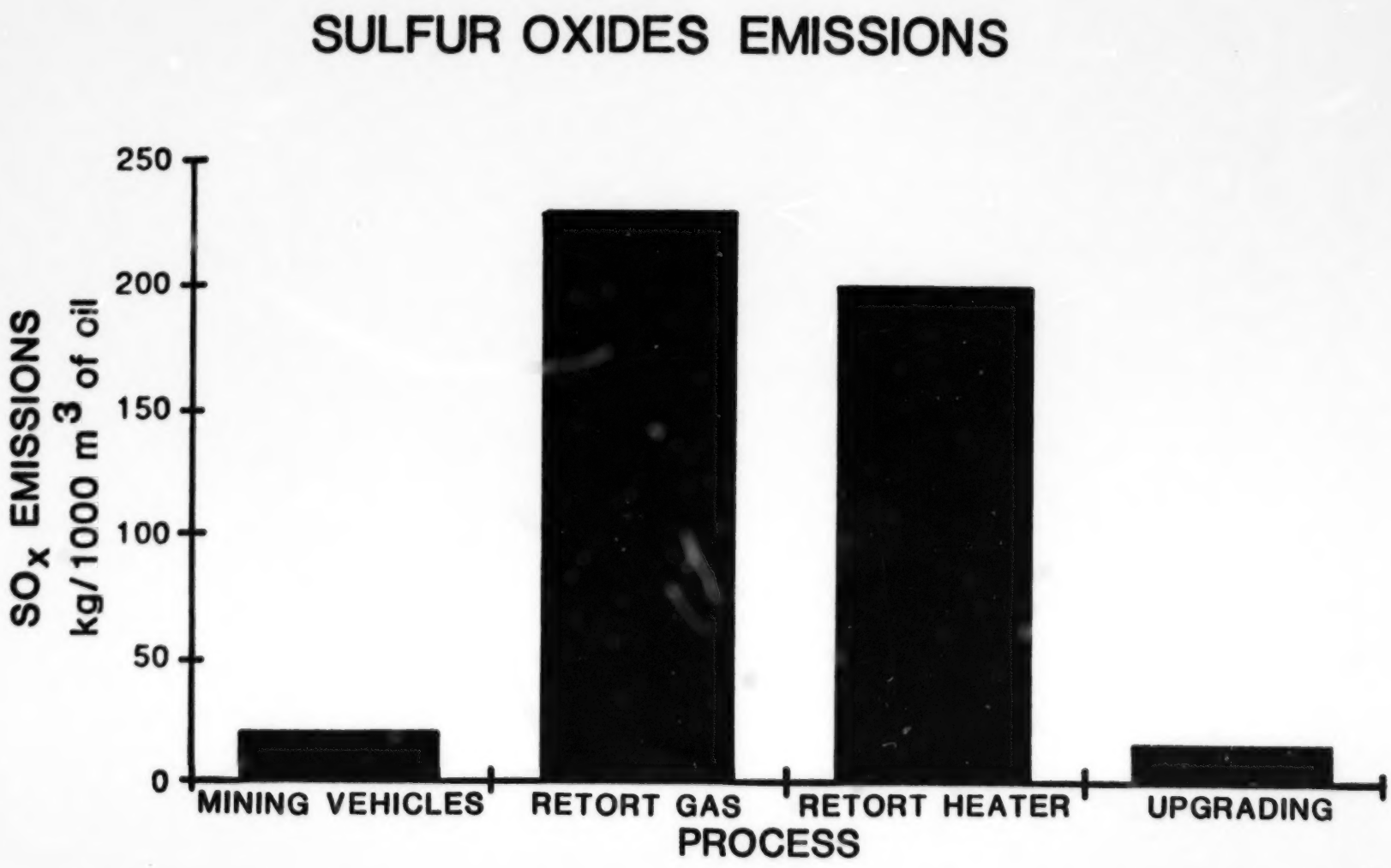
SULFUR OXIDES EMISSIONS
250
200
150
100
50
0
SOx EMISSIONS
kg/1000 m3 of oil
MINING VEHICLES
RETORT GAS
RETORT HEATER
UPGRADING
PROCESS

Figure 7.

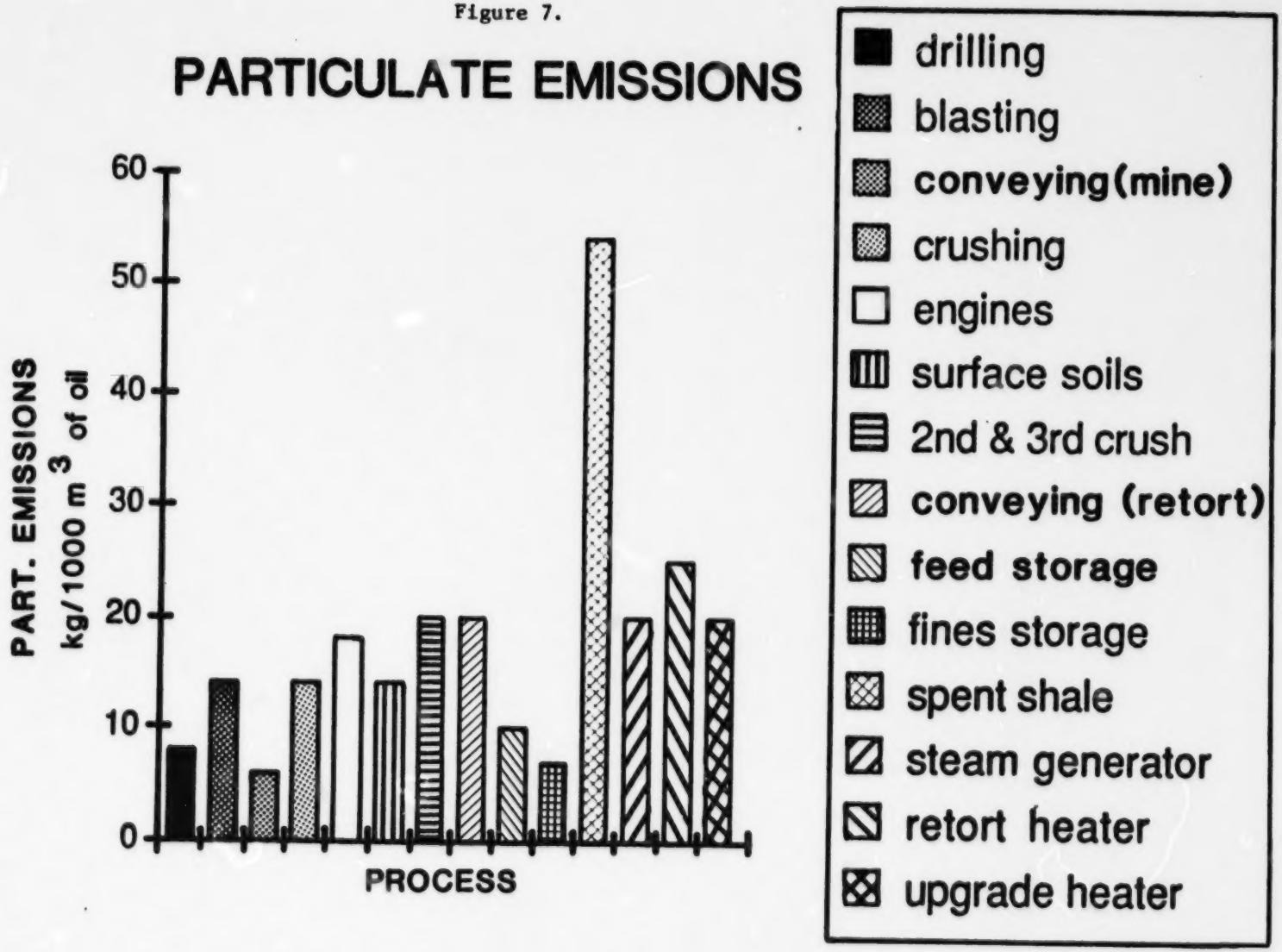
PARTICULATE EMISSIONS
PART. EMISSIONS
kg/1000 m3 of oil
60
50
40
30
20
10
0
PROCESS
drilling
blasting
conveying(mine)
crushing
engines
surface soils
2nd & 3rd crush
conveying (retort)
feed storage
fines storage
spent shale
steam generator
retort heater
upgrade heater

Figure 8.

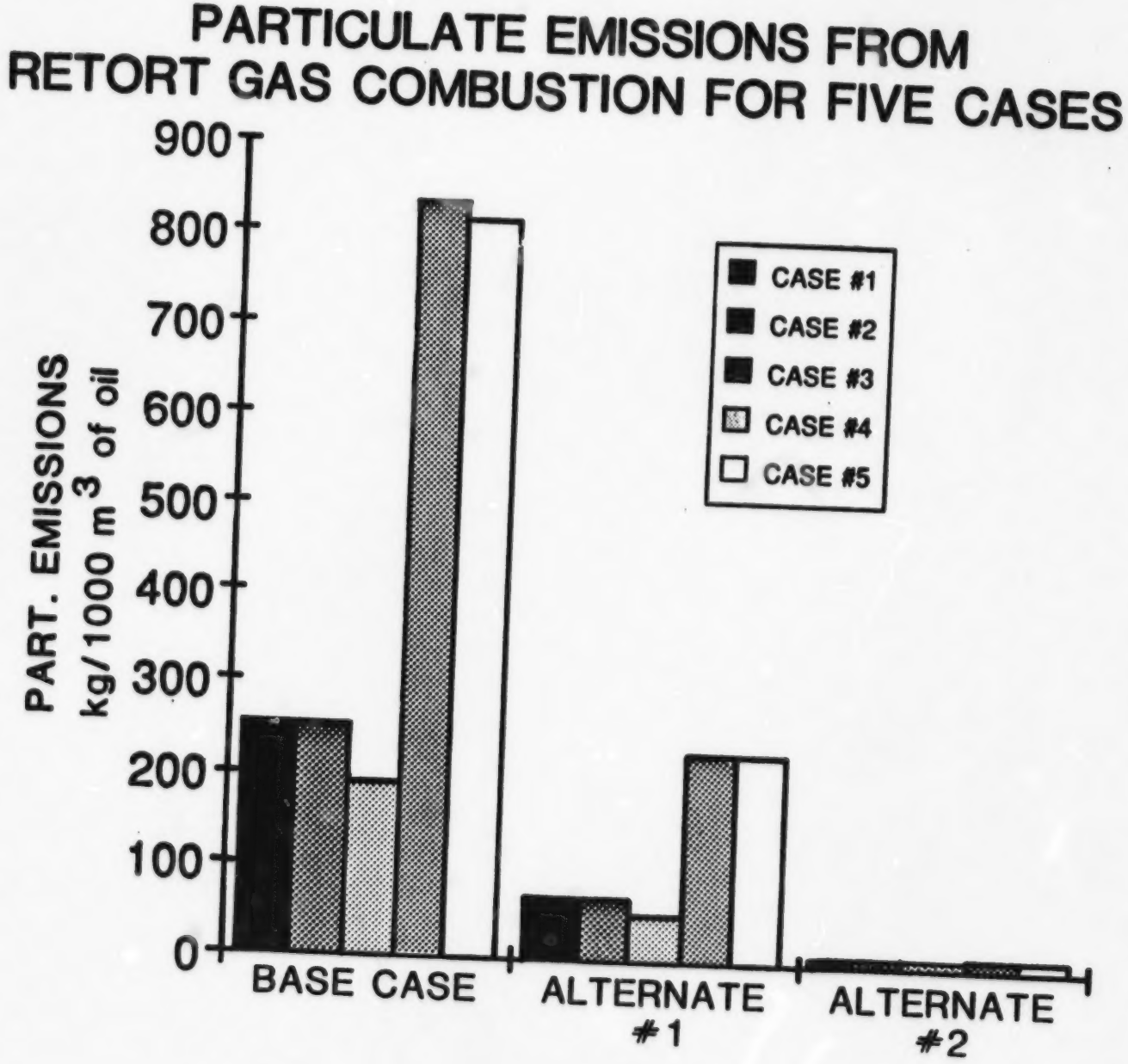
PARTICULATE EMISSIONS FROM
RETORT GAS COMBUSTION FOR FIVE CASES
PART. EMISSIONS
kg/1000 m3 of oil
900
800
700
600
500
400
300
200
100
0
CASE #1
CASE #2
CASE #3
CASE #4
CASE #5
BASE CASE
ALTERNATE #1
ALTERNATE #2

Figure 9.

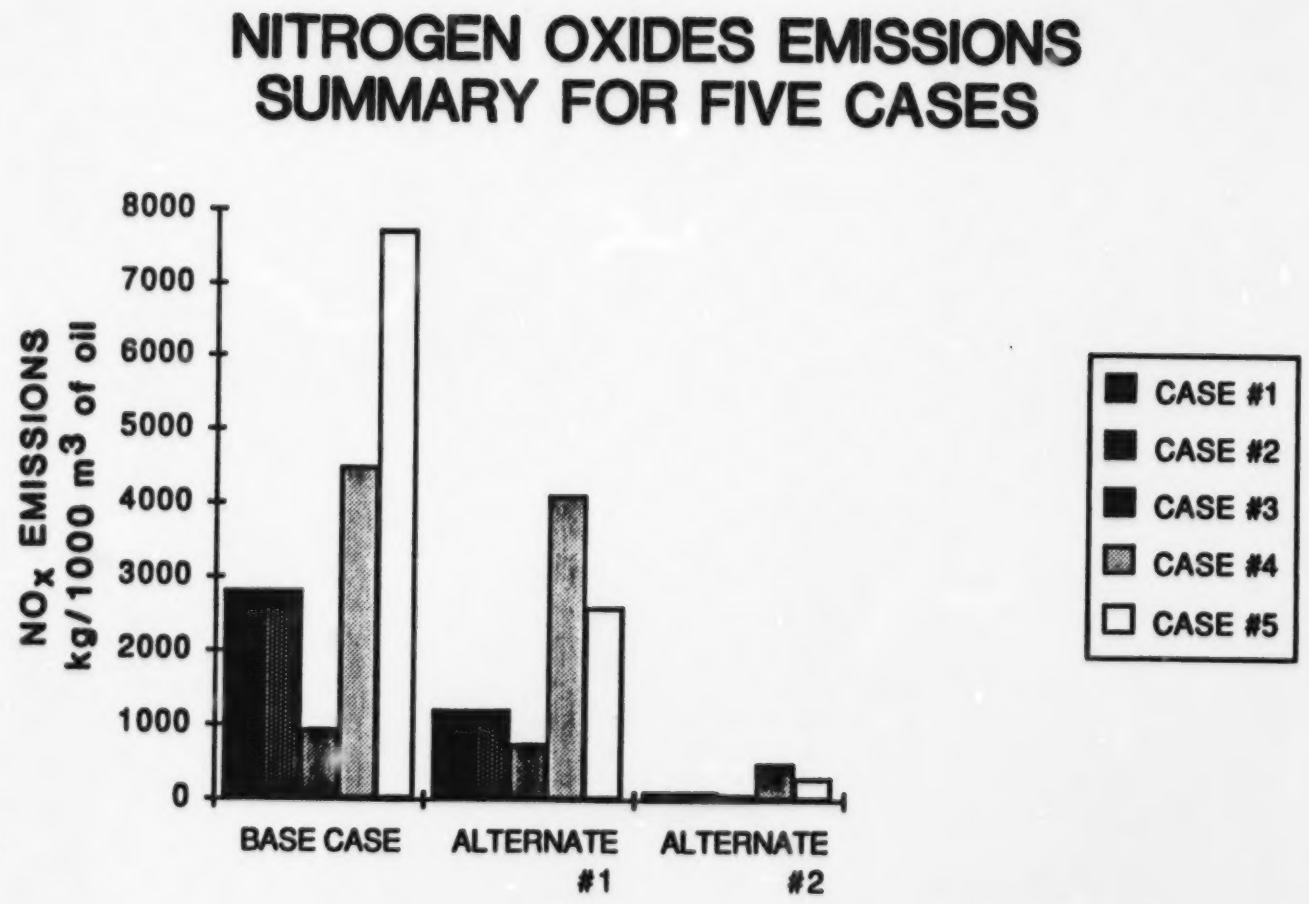
NITROGEN OXIDES EMISSIONS
SUMMARY FOR FIVE CASES
NO_x EMISSIONS
kg/1000 m^3 of oil
8000
7000
6000
5000
4000
3000
2000
1000
0
BASE CASE
ALTERNATE #1
ALTERNATE #2
CASE #1
CASE #2
CASE #3
CASE #4
CASE #5

Figure 10.

SULFUR OXIDES EMISSIONS SUMMARY FOR FIVE CASES

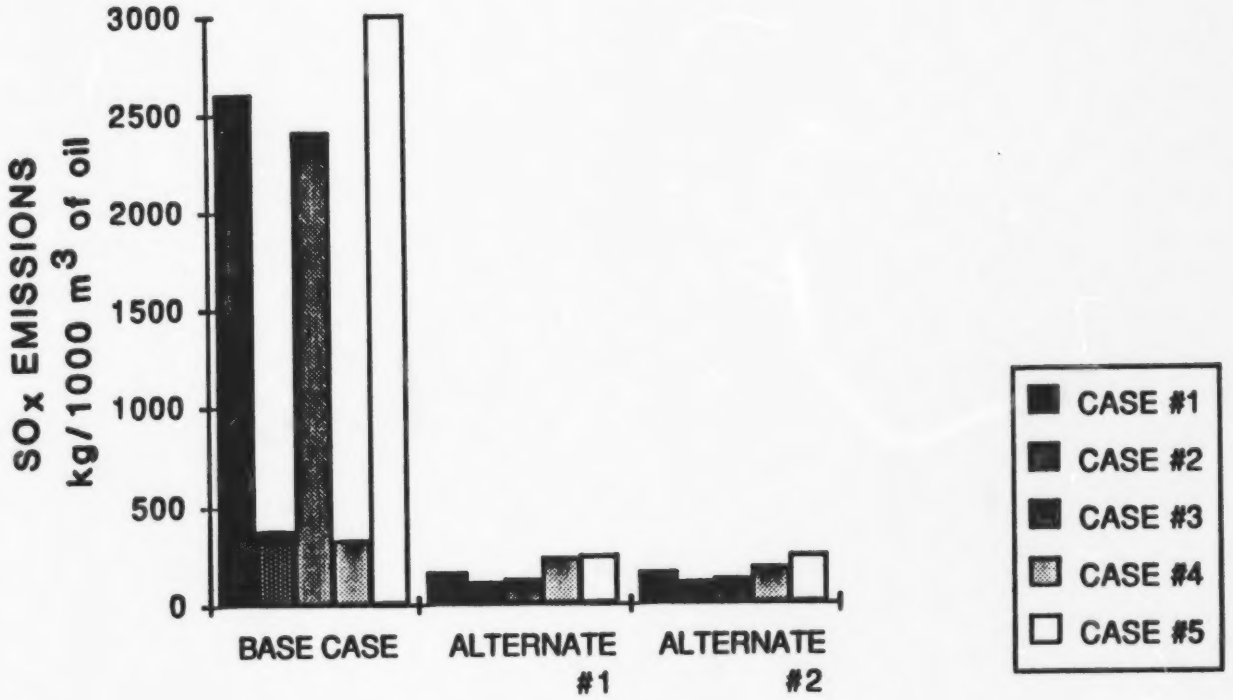

Figure 11.

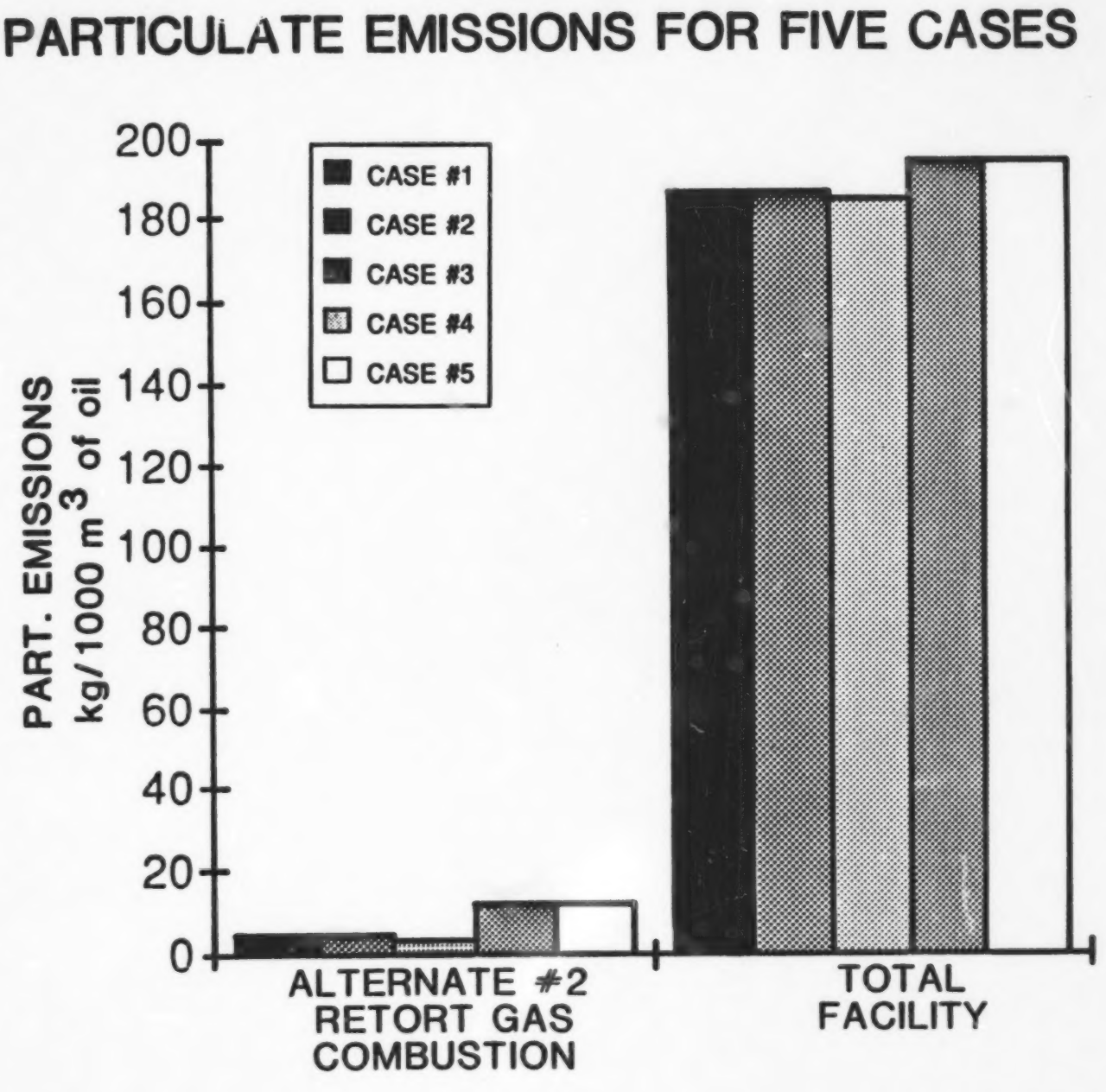
PARTICULATE EMISSIONS FOR FIVE CASES
PART. EMISSIONS
kg/1000 m3 of oil
200
180
160
140
120
100
80
60
40
20
0
CASE #1
CASE #2
CASE #3
CASE #4
CASE #5
ALTERNATE #2
RETORT GAS
COMBUSTION
TOTAL
FACILITY

Figure 12.

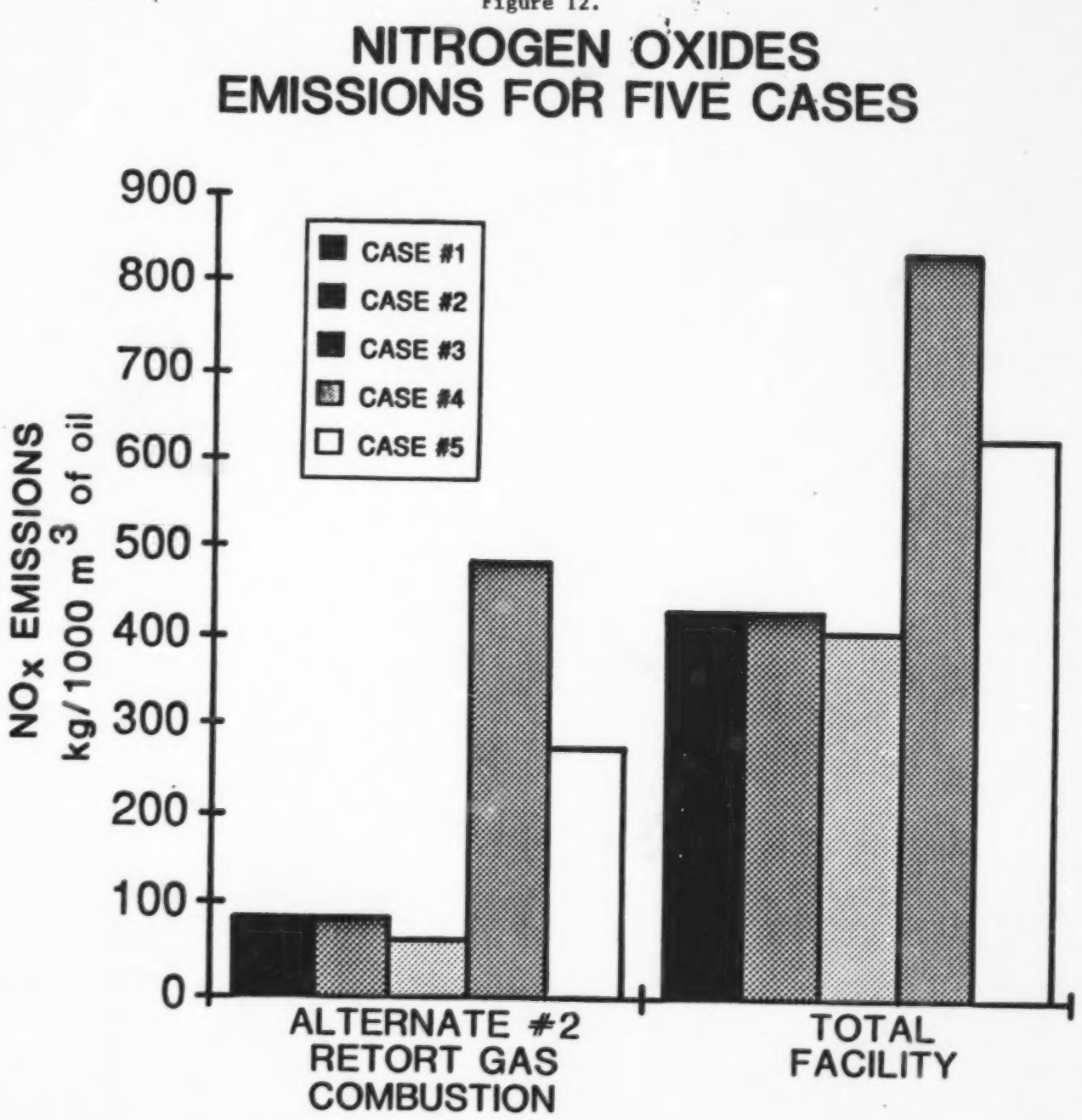
NITROGEN OXIDES
EMISSIONS FOR FIVE CASES
900
800
700
600
500
400
300
200
100
0
NOx EMISSIONS
kg/1000 m3 of oil
CASE #1
CASE #2
CASE #3
CASE #4
CASE #5
ALTERNATE #2
RETORT GAS
COMBUSTION
TOTAL
FACILITY

Figure 13.

SULFUR OXIDES EMISSIONS FOR FIVE CASES